Advanced Metering Business Case Including Demand Side Management Benefits

Report for Delaware

Before The Delaware Public Service Commission – Docket No. 07-28

August 29, 2007

Executive Overview and Conclusion

Overview

The Delaware Public Service Commission (the "DPSC" or "the Commission") issued Order No. 7154 initiating this proceeding, Docket No. 07-28 on March 20, 2007. There have been several workshop meetings and discussions among the parties with the development and submission of this initial AMI business case as the next step in the process. As demonstrated in the following report, the AMI business case for Delmarva is justified by the operational benefits and the demand response benefits to the Company and our customers. Pepco Holdings, Inc. ("PHI"), the parent company of Delmarva Power & Light Company ("Delmarva" or "the Company"), Pepco and ACE has proposed their Blueprint for the Future (see February 6, 2007) that addresses two important local and national challenges: the rising cost of energy and the impact of energy use on the environment.

As regulated public utilities, we are uniquely positioned to play a leadership role in helping to meet both of these challenges. The Blueprint builds on the work we already have begun through Utility of the Future and other initiatives. In summary, Delmarva's Blueprint focuses on implementing advanced technologies and energy efficiency programs to improve service to our customers and enable them to manage their energy use and costs. If we can provide tools for our customers to control their energy use we can make a sizeable contribution to meeting the nation's energy and environmental challenges and at the same time help our customers keep their electric and natural gas bills as low as possible.

The Blueprint for the Future charts the course we believe we must follow to give our customers what they tell us they want: reasonable and stable energy costs; responsive customer service; power reliability; and environmental stewardship.

Delmarva is deploying a number of innovative technologies. Some, such as the automated distribution system, will help to improve reliability and workforce productivity, while others, including an Advanced Metering Infrastructure ("AMI"), will enable our customers to monitor and control their electricity use, reduce their energy costs and enable their participation in innovative rate options. Here are some examples of what's planned:

Demand Side Management (DSM) Programs

Delmarva plans on working closely with the SEU (Sustainable Energy Utility) to assure a portfolio of energy efficiency programs in the state that will work together to benefit our customers. Our primary focus will be on the demand response programs, as they are closely tied to the technology investments of the company. We will, however, in cooperation with the SEU develop appropriate energy efficiency programs to compliment, and supplement the SEU. A special effort with our consumer council will be taken to develop programs geared toward low-income customers who can also benefit from the advantage of this technology.

Automated Metering Infrastructure (AMI)

We will work collaboratively with the Commission to phase in the installation of an AMI system in the homes of Delmarva gas and electric customers. The AMI system will provide detailed usage data to our customers, our electricity suppliers and to the Company. The system will not only enable customers to track and modify their electric use, but it will also help us make improvements to customer reliability, outage management, and billing accuracy and timeliness.

Environmental Considerations

The deployment of an AMI System will support innovative customer rate options that help to support plug-in vehicles and small-scale renewable generators. The SEU has indicated that one of the primary benefits of this technology, to support their efforts, will be the ability to better pinpoint areas where distributed generation will provide overall system benefits. As part of PHI's multifaceted environmental initiatives, PHI is also laying the groundwork to transform its 2,000-vehicle fleet to more environmentally friendly technologies. We are already using Biodiesel at PHI fueling sites; we have replaced a number of our fleet vehicles with hybrid vehicles; and we are collaborating with the Electric Power Research Institute ("EPRI") on a project to demonstrate plug-in gasoline/electric vehicles.

In addition to these programs, the demand response efforts enabled by this technology will allow for reduced dependence on peaking sources of generation, while the technology will improve our access to greener sources of supply.

Delmarva's Blueprint for the Future Plan

Over the past several years the rising cost of energy across the nation has adversely affected Delmarva's customers, who are often left with limited ability to lower their energy use to reduce the added burden of higher energy costs. Delmarva has communicated with its customers and attempted to provide them with options to more efficiently manage their energy use. Last year PHI and Delmarva launched the "Energy Know How" campaign, which was recently re-intoduced under the name of "My Account". PHI and Delmarva invested over $1,000,000 to implement state of the art energy auditing software. This investment now enables Delmarva's residential customers to go on the internet and view data about their monthly bills to better understand how they use energy and what changes might reduce their overall costs. This was a good first step, but much more needs to be done to allow customers to further control their bills. The Blueprint is Delmarva's proposal to take Delaware customers into the future.

This filing is the next step in answering customer concerns by giving customers more robust energy efficiency tools to reduce electricity consumption and demand response programs that will help to change when customers use energy in an effort to reduce peak demands, driving total electricity costs down for the state. The data and communications capabilities inherent in the advanced metering proposal that Delmarva has set forth will provide a platform upon which to build a number of programs aimed at managing overall energy costs. Delmarva envisions that ultimately the new technology will even have customers' appliances receive and react to real time energy prices. Some of these technologies will take time and need to be tested, but many are ready to roll out immediately.

Components of Delmarva PHI AMI business case

The Business Case is comprised of four major components: Energy Delivery Benefits from AMI, Customer Savings from Reductions in Peak Loads, Cost to Deploy, and Accelerated Depreciation. The information contained in each of these components is further described below and detailed in the body of this report.

1 - Energy Delivery Benefits from AMI

Savings in operating costs captures O&M and capital savings expected to be realized once the AMI is implemented. These savings or benefits will include:

- Meter Related Benefits
- Customer Contact Benefits
- Asset Optimization Benefits
- Additional Benefits

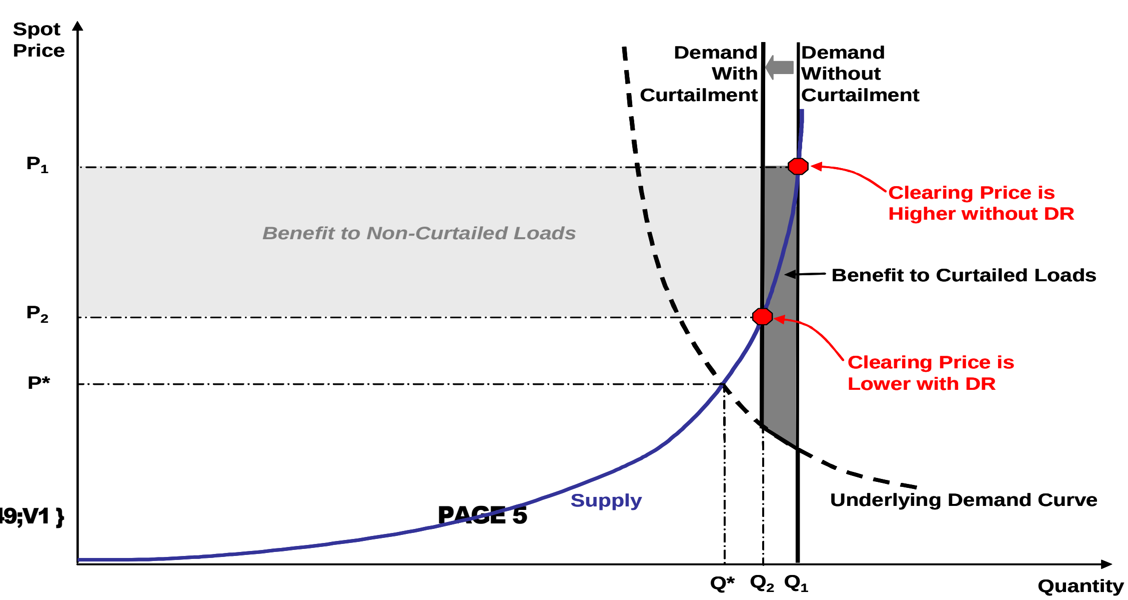
2 - Customer Savings from Reductions in Peak Loads

This analysis estimates the cost savings Delmarva's DSM programs are likely to achieve by (1) reducing the need for capacity, energy, and ancillary services (i.e., the "resource cost savings"); and (2) depressing market prices for energy and capacity by reducing demand. **The benefits are estimated consistently with the January, 2007 *Brattle* Study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI), with several additional analytical elements.**

The resource cost savings reflects the fact that every MW reduction in peak load lessens the need for physical capacity, which customers pay for through the load serving entities' payments. Similarly, every MWh reduction in consumption lessens the quantity of generation that customers must buy during peak periods with very high prices.

In general, the market price impacts reflect the fact that even a small reduction in demand during tight market conditions lowers the market price for energy, thus lowering the cost of energy for all customers (not just those curtailing load), as illustrated in Figure 1. Similarly, reducing the peak demand lowers the demand for capacity and thus reduces market prices for capacity, which affects all customers.

Figure 1: The *Brattle*-PJM-MADRI Study Showed How Even Small Changes in Demand Can Lead to Large Changes in Prices and Customer Benefits



3 - Cost to Deploy

Cost to Deploy includes the cost of the capital investments associated with building out the AMI system. Deployment costs included are; meters and installation, communications network infrastructure and installation and the associated information technology systems and integration, including the meter data management system (MDMS). Also included in the Cost to Deploy are the Incremental operating cost for the AMI system. Incremental operating costs include O&M expenses associated with operating the AMI. This includes; MDMS Software, Maintenance and license fees, AMI network management software maintenance and license fees, hardware lease expense for application and storage servers and expenses related to the communications network infrastructure.

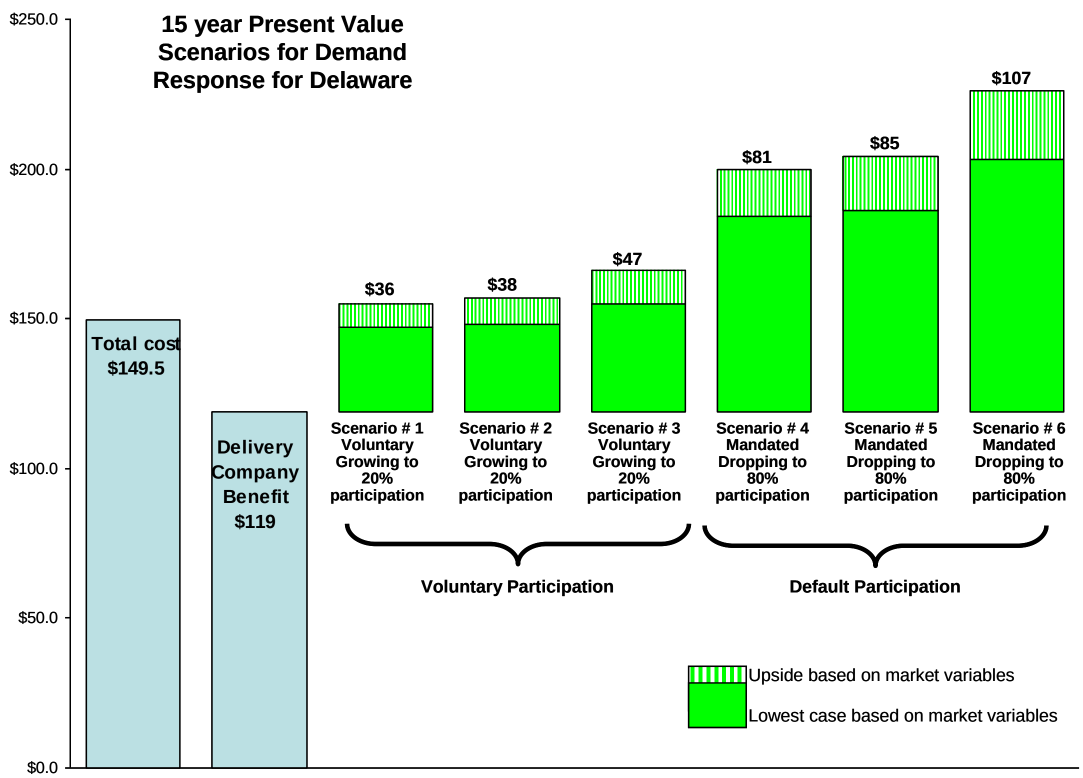
4 - Accelerated Depreciation

The deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. These impacts have been reflected in the analysis. Depreciation calculations may be updated due to pending Federal legislation.

Conclusions

The Delmarva AMI business case is justified by the operational benefits and the demand response benefits to the Company and our customers. The estimates for demand response benefits from the AMI deployment, over a 15 year period, is $36 million estimated using the most conservative of scenarios. Coupled with operational savings of $119 million, results in a positive $5.5 million Present Value Revenue Requirement (PVRR) over the same period. Using the best case for Demand Response (DR) benefits, results in a positive $76.5 PVRR.

Figure 2



In order to arrive at this conclusion, PHI contracted with the Brattle Group to develop six scenarios of customer and supplier response to AMI. Figure 2 above, shows the relationship of each of these six scenarios compared to the PVRR Cost and Benefit. The two cases, upside and low, for each scenario are the result of sensitivities associated with variations in market conditions. These conditions include possible fluctuations in fuel prices, and or high peak years (usually weather driven). Following PHI's example, if the other energy distributors in PJM deploy AMI, the benefit to Delaware customers is estimated to be as high as $393.5 million.

The results of this analysis yields two key conclusions: (1) AMI is a net positive investment even in the lowest value scenario; (2) the benefits from AMI-enabled DR will be more than twice as large if dynamic pricing is the default rate structure than if it is merely an option that customers can elect.

Figure 3 below summarizes the PVRR for Delmarva Delaware.

Figure 3

Line	AMI System Components	Initial Deployment Costs Only $ in ('000s) Electric	Gas	Combined
1	Meters, including Installation Cost	$ 42,783	$ 9,195	$ 51,978
2	Communications Network, including Installation Cost	$ 21,616	$ -	$ 21,616
3	AMI Network Management System and Meter Data Management Sy	$ 4,417	$ 1,828	$ 6,245
4	Contingency	$ 4,680	$ 1,543	$ 6,223
	Total Capital Investment	$ 73,496	$ 12,566	$ 86,062

Line	AMI System Incremental Cost to Operate	Annual Estimated Costs After Deployment $ in ('000s) Electric	Gas	Combined
5	MDMS Software Maintenance & License Fees	$ 62	$ 26	$ 88
6	MDMS Hardware Leasing	$ 168	$ 70	$ 238
7	AMI Network Management System O&M	$ 196	$ 81	$ 277
8	Communications Network Infrastructure O&M	$ 273	$ -	$ 273
	Total Incremental Cost to Operate	$ 699	$ 177	$ 876

15 Year Revenue Requirement of Total Costs	***$149.5 million***

Line	Benefit Category	In Projected 2008 Dollars ('000s) Electric	Gas	Combined
1	Eliminate Manual Meter Reading Costs	$ 3,564	$ 1,157	$ 4,721
2	Implement Remote Turn-on/Turn-off Functionality	$ 1,592	$ -	$ 1,592
3	Improve Billing Activities	$ 484	$ 186	$ 670
4	Reduce Off-Cycle Meter Reading Labor Costs	$ 372	$ 57	$ 429
5	Asset Optimization	$ 219	$ -	$ 219
6	Reduce Expenses Related to Theft of Service	$ 88	$ 36	$ 124
7	Eliminate Hardware, Software, Maintenance and Operations Cost	$ 75	$ 30	$ 105
8	Reduce Volume of Customer Call Types Related to Metering	$ 29	$ 12	$ 41
9	Reduced Complaint Handling	$ 24	$ 10	$ 34
	Total Annual Operating Benefits	$ 6,447	$ 1,488	$ 7,935

15 Year Revenue Requirement of Operating Benefits	***$119 million***

Summary of Cost and Benefits for Delmarva Delaware

Business Case Report Details

Organization of this Report

For the preparation of this report, PHI gathered information from both internal and external subject matter experts, including IBM and the Brattle Group, as well as from other utilities across the country. While this report represents the current state of thinking for AMI deployment, information within this report is still subject to change. Therefore this report should be considered a living document that will be consistently updated as additional information becomes available. Specific points to remember are:

- AMI Capital Costs reflected in this report are estimates. Once PHI secures an AMI Vendor(s), the final Capital Cost numbers will be updated.
- This Business Case considers the deployment of an AMI system throughout all PHI jurisdictions.
- Cost and Benefit estimates are realistic yet conservative in order to assure a high probability of achievement.
- While many benefits are immediately available as the AMI System is deployed, timing of the full benefits associated with an AMI system is assumed to begin following the complete deployment.
- Business Case Financial Assumptions:
    - 15 year Present Value Revenue Requirement model, with multiple jurisdictions modeled
    - Meter Deployment assumed 100% of Delmarva DE meters in 2009:
    - Meter growth is assumed to be 1% per year
    - 3% labor and expense annual escalation rate
    - Cost of Capital
        - Delmarva-DE Elec: 6.23%
        - Delmarva-DE Gas: 6.55%
    - Tax rate 40.4% for all jurisdictions
    - Depreciation:

- New meter and meter communications equipment - 15 yrs
- Existing meter and equipment – 5 years
- IT Capital Cost - 5 years

Energy Delivery Benefits from AMI

This section of the report describes the estimated benefits[1] that could be realized by Delmarva's electric and gas delivery businesses through deployment of the advanced metering infrastructure system and the associated meter data management system. Typically, the full value realized from the benefits is expected to occur after full deployment of the AMI system. The Company proposes to use these quantified benefits to help offset the costs associated with AMI and MDMS in the proposed AMI Adjustment Mechanism as described in the Appendix to the February 6, 2007 Blueprint for the Future filing with the Delaware Public Service Commission. Figure 4 below summarizes the annualized benefits and under the Figure are more detailed descriptions of each benefit.

Figure 4 (In $ Millions)

		In Projected 2008 Dollars			Benefit Dollars as a % of Total		
Line	Benefit Category	Delmarva DE-Elec	Delmarva DE-Gas	Delmarva Combined	Delmarva DE-Elec	Delmarva DE-Gas	Delmarva Combined
1	Eliminate Manual Meter Reading Costs	$ 3,564	$ 1,157	$ 4,721	55.3%	77.8%	59.5%
2	Implement Remote Turn-on/Turn-off Functionality	$ 1,592	$ -	$ 1,592	24.7%	0.0%	20.1%
3	Improve Billing Activities	$ 484	$ 186	$ 670	7.5%	12.5%	8.4%
4	Reduce Off-Cycle Meter Reading Labor Costs	$ 372	$ 57	$ 429	5.8%	3.8%	5.4%
5	Asset Optimization	$ 219	$ -	$ 219	3.4%	0.0%	2.8%
6	Reduce Expenses Related to Theft of Service	$ 88	$ 36	$ 124	1.4%	2.4%	1.6%
7	Eliminate Hardware, Software, Maintenance and Operations Cost	$ 75	$ 30	$ 105	1.2%	2.0%	1.3%
8	Reduce Volume of Customer Calls Related to Metering	$ 29	$ 12	$ 41	0.4%	0.8%	0.5%
9	Reduced Complaint Handling	$ 24	$ 10	$ 34	0.4%	0.7%	0.4%
10	Total	$ 6,447	$ 1,488	$ 7,935	100.0%	100.0%	100.0%

1) Eliminate Manual Meter Reading Costs

This is the largest operational benefit expected to be realized after full deployment of the AMI system. As of June 2007, Delmarva employed a total of 55 meter readers and supervisory personnel in Delaware, all of which would no longer be needed to perform their present functions with full deployment of AMI. As of the date of this report, which is prior to

[1]The quantification of these benefits will change as Delmarva conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated value of the benefits.

development of the request for proposal for the procurement of the AMI system, the Company expects to design and configure its AMI such that all Delaware customers will have meters that are reachable by the AMI's communications network infrastructure. The elimination of the need to manually read meters would result in annualized O&M expense savings of $4.7 million (expressed in projected 2008 dollars). The O&M expense savings estimate is based on the actual 2007 salaries of the 55 people with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The savings also include 2007 budgeted overtime, vehicle and miscellaneous expenses associated with the manual meter reading.

The savings were allocated between electric and gas service using a three step approach. First, the meter reading personnel working in the Delaware portions of Delmarva's New Castle and Bay regions were specifically identified with the Bay region costs assigned completely to the electric service. The New Castle region costs were then allocated between electric and gas service using the allocation factor the Company currently uses in its accounting practices to allocate the meter reading costs between electric and gas service. This allocation factor was updated in late 2006 and is presented in the Figure below. Finally, the portion of the New Castle region's expenses allocated to the electric service were added to the specifically identified Bay region expenses in order to derive the total electric savings for Delaware.

Figure 5 below is the allocation factor for New Castle region's meter reading in the Christiana operating center, which is entirely in the state of Delaware:

Figure 5

Meter Reading Analysis :

Description	Source	Number	% of Total	Gas %	Gas % of Total
Accounts read in Christiana Region	November 2006 Report BCR074 [C3]	341,757			
Combined Gas& Electric Premise	DB2 Extract from C3 November 2006	110,489	47.8%	50.0%	23.9%
Total Premises Visited	Total less combined	**231,268**			
Gas customer accounts	Monthly SAP 661 - November 2006	120,781			
Combined Gas& Electric Premise	DB2 Extract from C3 November 2006	110,489			
Gas Only Premise	Gas cust less G&E combined	10,292	4.5%	100.0%	4.5%
Electric Christiana Customer accounts	Total Accounts less Gas Accounts	220,976			
Combined Gas& Electric Premise	B. Dodge - C3 November 2006	110,489			
Electric Only Premise	Chris. Elec. Cust less G&E comb	110,487	47.8%	0.0%	0.0%
		Gas Delivery Meter Reading %			**28.3%**

The initial year was assumed to be 2008 therefore the 2007 O&M expense savings as described above were escalated three percent (3%) to account for expected wage and inflation increases. The three percent escalation factor was also used to grow the estimated annualized savings in the remaining years of the revenue requirements schedule

2) Implement Remote Turn-on/Turn-off Functionality

Delmarva's current assumption is that a switch will be available inside the meters that will permit the Company to remotely connect and disconnect 200 AMP and less electric service. This assumption is consistent with AMI recent experiences and plans of other utilities and requirements of other state public service commissions. This type of switch would not be used for the gas type of service therefore gas connections and disconnections would continue to be done using the existing work processes.

The estimated savings associated with this benefit is comprised of two components. First, there would be savings from avoiding field visits to customers' premises conducted at the customers' requests to turn-on or turn-off electric service. Based on a review of 2006 data from Delmarva's accounting system, there were approximately 12,000 labor hours used for residential turn-on and turn-off orders. This translates into approximately seven to eight (7 to 8) Full Time Equivalents (FTE). The Full Time Equivalent employee concept was used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized $0.8 million (expressed in projected 2008 dollars).

The second component of the savings would come from avoiding field visits to customers' premises for collection reasons, both the initial cut/collect field visit and the reconnection field visit, if such a reconnection visit was requested by the customer. Based in a review of 2006 data from the Company's accounting system, there were approximately 10,000 labor hours used for residential field collection and reconnection visits. This translates into approximately six to seven (6 to 7) full time equivalents (FTE). Full time equivalents were used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized $0.7 million (expressed in projected 2008 dollars).

Remote turn on/turn off capability will benefit all customers, especially those subject to disconnection for non-payment. Currently the Delaware tariff specifies that if a disconnected customer requests to be reconnected, then a charge of $75.00 to $175.00 is required (depending on the time of day). With AMI's remote connection and disconnection functionality, this charge could be significantly reduced (estimated in the range of $5 to $10). The reconnection could be accomplished remotely from Delmarva's offices, after the customer calls the Company to verify payment, rather than dispatching a person to the customer's premise. This reduces the financial burden on those having difficulty paying their bills. This method is also safer for employees who perform this type of work.

3) Improve Billing Activities

With the deployment of AMI, the Company expects to significantly reduce the volume of exceptions that it currently addresses in its billing department. These exceptions include such transactions as estimated bills, consecutive estimations, high/low consumption and other checks. Delmarva and Atlantic City Electric Company (ACE) operate their billing department on an integrated basis using the same customer information system (CIS). As of June 2007, Delmarva and ACE employed a total of 28 billing analyst and supervisory personnel to handle the exceptions work volume. For this benefit, Delmarva assumed 90% of the work performed by these personnel would be eliminated with full deployment of AMI which translates into the elimination of the cost of 25 full time equivalents. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees (analysts and supervisors) doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized $1.9 million (expressed in projected 2008 dollars) for all of Delmarva and ACE combined. Note that if less than 90% of the exception volume is ultimately realized, then the savings estimate will be adjusted accordingly.

The savings were allocated between the Company's electric and gas types of service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor. This allocation factor is presented in the Figure below.

Figure 6

Allocation based on 2007 Budgeted Customer Counts			
ACE	543,437	47%	$ 849,577
Delmarva-DE-Electric	296,159	26%	$ 469,979
Delmarva-DE-Gas	119,403	10%	$ 180,761
Delmarva-MD	200,350	17%	$ 307,294
Combined	1,159,350	100%	$ 1,807,611

The 2007 dollars in Figure 6 above were escalated by three percent (3%) to account for 2008 estimated wage increases which increases the dollars in Figure 6 from $1.8 million to $1.9 million.

4) Reduce Off-Cycle Meter Reading Labor Costs

Delmarva typically uses meter readers, meter technicians, service persons and trouble persons to obtain meter readings outside of the normally scheduled meter reading routes for a variety of reasons. These reasons include when a customer moves out of a premise and a new customer moves in shortly thereafter and asks the billing department or the call center to check a reading in the field. With the full deployment of AMI, these "check reads" can be obtained remotely from Delmarva's offices eliminating the need for a field visit. When computing the estimated savings associated with this benefit, any costs from meter readers were excluded. Those savings are included in meter reading benefit described above.

Based on a review of 2006 data from the Company's accounting system, there were approximately 4,700 labor hours used for electric meter "check reads" and about 700 labor hours used for gas meter "check reads". This translates into approximately three to four (3 to 4) full time equivalents (FTE) for electric meters and approximately one half of a FTE for gas meters. Full time equivalents were used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit above. This portion of the savings amounted to an estimated annualized $0.4 million (expressed in projected 2008 dollars).

5) Asset Optimization

AMI deployment will improve the quality of customer outage status and hence will reduce the field restoration efforts associated with "false" power outages. Delmarva-DE experiences approximately 1000 power outage calls annually where upon arrival at the customer locations, the emergency response team finds that there is no electric service problem from Delmarva but the problem is on the customer side of the meter or in the house. Similarly, during storms, the Company responds to 500 to 600 outage requests annually which have been already restored previously but not recorded in the Company outage management system. AMI capabilities will eliminate these unproductive trips as well as reduce the number of Call Center calls and will result in estimated savings of $179,000. AMI deployment also will improve Delmarva's asset management program and will result in accurate sizing of transformers and fuses. This will result in reduced outages and is expected to reduce number of field trips by 250 annually. It will also reduce field trips associated with special load readings at substations. The savings associated with this benefit is $ 40,000 annually.

6) Reduce Expenses Related to Theft of Service

Delmarva currently uses an outside firm to analyze commercial account data to provide internal field investigators with selected accounts that may be experiencing tampering, energy diversion or some sort of metering problem. Based on discussions with MDMS vendors, it appears that with data coming from the AMI system coupled with analytical capabilities of the MDMS, Delmarva will be better equipped to conduct these types of analyses on its own and could therefore eliminate this contractual relationship. The savings were allocated between the Delmarva electric and gas service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

7) Eliminate Hardware, Software, Maintenance and Operations Cost

PHI currently pays maintenance fees on its existing hand held metering reading devices and also employs two employees to operate and maintain the devices and associated data. With the deployment of AMI, these costs would be eliminated. The O&M expense savings for the two employees is based on the actual 2007 salaries of the two people with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The costs and savings were allocated between the Delmarva's electric and gas service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

8) Reduce Volume of Call Types Related to Metering

PHI operates its call centers for Delmarva and ACE on an integrated basis using the same customer information system (CIS). In 2005 and 2006, PHI received about 40,000 customer calls related to metering. If this associated call volume were reduced after the full deployment, the call center could save two full time equivalents. The O&M expense savings for the FTEs is based on the actual salary for a customer service representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits multiplied by two FTEs. The costs and savings were allocated between Delmarva's electric and gas service in Delaware, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

9) Reduced Complaint Handling

PHI operates its complaint handling group for Delmarva and ACE on an integrated basis using the same customer information system (CIS). For this benefit, PHI is assuming the data from AMI will, over time, contribute to fewer complaints and that the company representatives may be able to more quickly resolve complaints. The current assumption is that the complaint handling group may be able to reduce one full time equivalent. The O&M expense savings for the one FTE is based on the actual salary for a company representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The costs and savings were allocated between Delmarva's electric and gas service in Delaware, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

Customer Savings from Reductions in Peak Loads

The Brattle Group was retained by PHI to estimate the value to customers of load reductions resulting from PHI's proposed investments in demand-side management (DSM) initiatives, including energy efficiency, direct load control, and deployment of advanced metering infrastructure. *Brattle*'s analysis involves two major components: first, determining the magnitude of load reductions that are likely to be achieved; and second, estimating the customer value of such load reductions.

1) Estimated Load Reductions

Load reductions associated with PHI's proposed programs involving energy efficiency and AMI-enabled direct load control are taken directly from PHI's most recent Blueprint Filing for its DSM programs. Load reductions associated with AMI-enabled critical peak pricing (CPP) programs were estimated using the PRISM model, which is based on empirical data from the California Statewide Pricing Pilot and is calibrated to the load characteristics of residential and small C&I customers in Delmarva Delaware. Assuming a CPP program similar to PEPCO DC's current CPP pilot becomes the default rate structure with 80% of eligible customers participating, the resulting load reductions would likely be quite substantial, as shown in Figure 7a. The load reductions would be less substantial if participation were voluntary, as shown in Figure 7b.

Figure 7a - Estimated Peak Load Reductions for Delaware from PHI's Initiatives, Assuming CPP is the Default Rate Structure (MW)

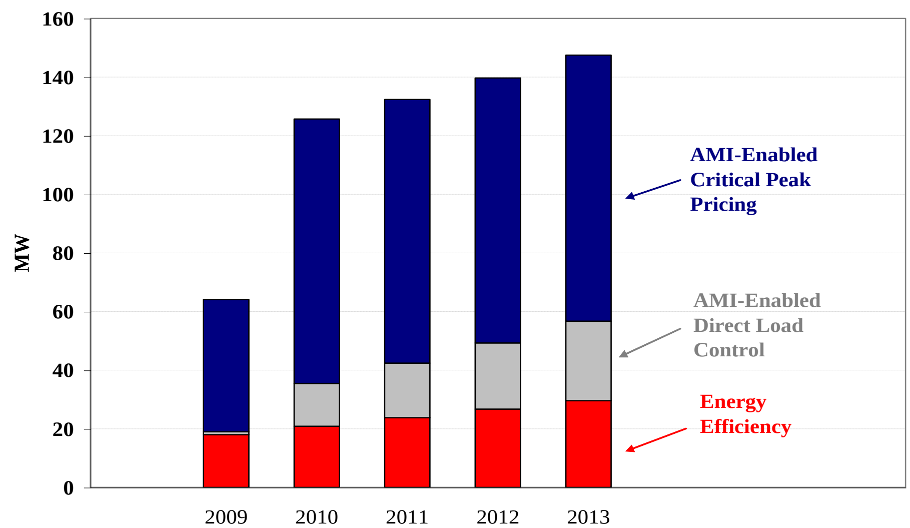
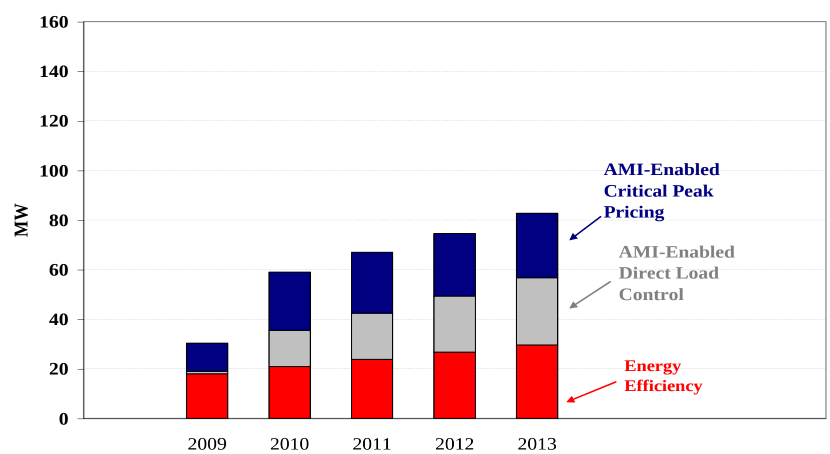


Figure 7b - Estimated Peak Load Reductions from PHI's Initiatives, Assuming CPP is a Voluntary Rate Structure (MW)



2) Analysis of Customer Benefits from Load Reductions

Savings to the customer relates to those benefits that will reduce the customer's bill, but not impact the cost of energy delivery. Most significantly, AMI-enabled innovative rate options (e.g., critical peak pricing, time of use rates, real-time pricing, etc.) will allow the customer to better manage consumption and thus reduce demand during peak periods. Reductions in peak consumption will produce savings by (1) reducing the need for supply-side capacity, energy, and ancillary services (i.e., the "resource cost savings"); (2) depressing market prices for energy and capacity by reducing demand; (3) reducing transmission losses; (4) improving reliability; (5) reducing rate volatility; (6) enhancing market competitiveness; (7) improving environmental quality or reducing energy prices by lowering the costs of environmental compliance; and (8) potentially obviating or delaying the need for investments in transmission and distribution.

The customer benefits detailed in this report focus on items one and two above. The other categories of benefits have not been quantified because the economic methodologies involved are not well developed or standardized. Therefore, the total benefits of reducing load could be substantially larger than the limited set of benefits reported in this Business Case.

The Brattle Group has estimated the benefits to Delaware customers from resource cost savings and market price impacts consistent with its January, 2007 study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI), but with several additional analytical elements.

Resource Cost Savings

Capacity savings reflect the fact that DR lowers the load forecast, which lessens the amount of capacity that load-serving entities must purchase from generation suppliers through contracts or through PJM's capacity market. Alternatively, load that is controlled directly by the utility can provide capacity, thus offsetting the need for physical capacity. The value of either approach – reducing the capacity requirement or contributing capacity – can be evaluated using a projected price of capacity. *Brattle* estimated the future capacity price using the Net Cost of New Entry (Net CONE) that PJM uses in its definition of capacity market parameters. Net CONE is a conservative proxy because the capacity price has been higher than Net CONE in recent auctions for the 2007/08 and 2008/09 delivery years. Net CONE is also less than the avoided capacity cost often used in

DSM plans, which often does not net out the marginal value (i.e., operating margins) that new generation would provide by selling energy and ancillary services.

Generation savings depends on the particular type of generation that is being avoided, which could come from a combination of new capacity not constructed and old capacity retired or not dispatched. The value of reduced generation is also partially offset by the value the customer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult to assess and depends on whether the customer shifts load to lower-priced periods. These issues were addressed in the *Brattle*-PJM-MADRI study, in which generation savings amounted to an additional 12-36 percent on top of the capacity savings. Brattle's analysis of AMI-enabled DR in Delmarva simply adopts these figures by adding 12-36 percent of the estimated capacity savings.

Some DR could provide spinning reserves or other ancillary services (A/S), which would reduce the need for reserves from supply-side resources, the marginal value of which is given by the market price for spinning reserves. However, ancillary service value is somewhat speculative because currently none of PHI's DSM programs plan to enable ancillary services, although other DR does provide small amounts of A/S in PJM and ISO-NE[2].

Short-Term Price Impacts

Short-term energy price reductions are estimated by adapting the results of the *Brattle*-PJM-MADRI study (January, 2007) to reflect the load reductions expected from PHI's programs. As in the Brattle-PJM-MADRI study, the "benefit" is given by the product of the estimated price reduction and the load exposed to market prices. Benefits are partially offset by an associated reduction in the value of Financial Transmission Rights ("FTRs") (about a 15% offset). To the extent that PHI's load reductions differ from the load reductions simulated in the *Brattle*-PJM-MADRI study, *Brattle* linearly extrapolated the price impacts (e.g., twice the amount of load reductions would lead to twice the price impact).

While the *Brattle*-PJM-MADRI study assumed that all non-curtailed load was exposed to market prices, the present analysis assumes conservatively that only a fraction of load is exposed to market prices. The remainder is unaffected because it is covered by pre-existing contracts that were priced without anticipating the effects of DSM. Roughly

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[2] *Brattle* assumed conservatively that AMI could eventually enable 100 MW of spinning reserves from loads that can be curtailed within less than 30 minutes of notification and stay offline for as much as 4 hours, such as electric arc furnaces or chillers in supermarkets. Hence potential ancillary service value is estimated by multiplying a conservative quantity of spinning reserves by the historical average price of spinning reserves (2004-06) of $8.5/MWh and by the number of hours in a year.

corresponding to the contract lengths and schedules by which standard offer service is procured in DC, DE, and MD and basic generation service in New Jersey, *Brattle* assumed that in any given year 50% of load-serving obligations are supplied by pre-existing wholesale contracts, and 50% are supplied by new contracts. This assumption results in discounted customer benefits relative to the *Brattle*-PJM-MADRI study – a 50% discount in the "Fast" Supply Response scenario and a 17% discount in the "Slower" scenario discussed below.

A second difference from the *Brattle*-PJM-MADRI study is the quantification of real-time DR benefits. The *Brattle*-PJM-MADRI study quantified benefits for only day-ahead DR and discussed qualitatively the potential additional value from DR that is dispatchable in real-time and thereby able to mitigate the effects of real-time surprises in supply and demand. In its present analysis of DSM in Delmarva, *Brattle* assumed that loads under direct load control were dispatchable in real time, and estimated the premium using the ratio of historical super-peak RT prices to super-peak DA prices. *Brattle* also estimated the additional value if dynamic pricing could designate peak periods on the day-of rather than day-ahead.

A third difference is that *Brattle*'s present analysis includes an estimate of the capacity price impact from DR, whereas capacity price impacts were outside the scope of the *Brattle*-PJM-MADRI. Participation of DR in capacity markets is an important element of PJM's newly instituted Reliability Pricing Model (RPM). While only the subset of load reductions, those that are under direct control (by the utility, other retail providers, curtailment service providers or the RTO), can participate as supply in capacity markets (Smart thermostat), the expected effect of dynamic pricing programs would also impact capacity prices by reducing the load forecast and thus the administratively-determined demand for capacity. Given this new market reality, *Brattle* has estimated capacity price impacts as follows: in the "Fast" and "Slower" Supply scenarios (defined below), the market was assumed to be in supply/demand balance with the expected 3-year forward capacity price set by Net CONE, irrespective of the level of load reductions achieved. Hence, the capacity price impact was conservatively set at zero in these scenarios. In the "Inadequate" Supply scenario, capacity price impacts were estimated by intersecting supply and demand curves for capacity in the Eastern MACC Locational Delivery Area both with and without DR. The demand curve was constructed using PJM's load forecast and the other parameters it uses to determine the administratively-determined demand curve. The supply curve was constructed by adding projected new supply (from the generation interconnection queue) to the supply curve available from the most recent capacity auction.

Scenario Definition

A key insight is that the resource cost savings from reducing peak loads persist over time, whereas the market price impacts can be expected to diminish as suppliers respond to depressed prices by delaying the construction of new generation or accelerating the retirement of existing plants. The magnitude and duration of the price impact depends on the rate at which suppliers respond to changes in market conditions and on the tightness of the market over the next several years. Price impacts are the largest and the longest-lasting in a scarcity situation; they are the smallest and shortest-lived in a surplus market or in a balanced market in which suppliers react quickly to DSM's successes (and associated price impacts) by delaying construction of new capacity or accelerating the retirement of existing plants. Hence, Brattle analyzed a range of plausible market conditions by constructing three supplier scenarios in which the longevity of price impacts is varied:

- In the "Fast" scenario, the market is in supply-demand equilibrium, and suppliers react quickly to changes in fundamentals. Short-term energy price impacts, as derived from the Brattle-PJM-MADRI study which used a short-term equilibrium model in which supply is static, benefits last for only one year before suppliers fully respond to DSM. One year after the introduction of new DR, suppliers have accelerated enough retirements and/or delayed enough new construction to completely offset the price impact of DR. Hence, if PHI's deployment schedule produces a 200 MW of total peak load reduction in year n and 300 MW in year n+1, then only 100 MW of load reductions has a price impact in year n+1. This scenario is consistent with the observation that suppliers in PJM's recent RPM Base Residual Capacity Auction for the 2008/09 delivery year changed their plans relative to the prior auction (in this case delaying retirements), presumably in response to high prices in the prior auction.

- The "Slower" scenario is similar to the "Fast" scenario except that short-term price impacts persist for three years before suppliers respond. The three-year response time corresponds to a three-year lead time for new construction.

- In the "Inadequate" scenario, suppliers do not build any capacity that is not currently in PJM's queue until 2015, and the market becomes very short on capacity. In such a shortage situation, suppliers are not responsive to the introduction of DR because they have no new capacity to delay and retiring existing plants early is unlikely, hence all load reductions achieved by PHI's DSM initiatives creates price impacts until 2015. This scenario reflects the possibility that suppliers are reluctant to build in the current uncertain environment with the threats of reregulation, high gas prices, climate change policies, and siting difficulties.

Finally, each supplier response scenario is analyzed assuming high rates of customer participation in dynamic pricing programs and, alternatively, low customer participation rates. Customer participation rates depend primarily on whether critical peak pricing becomes the default rate structure or merely an option that customers can elect. In the "CPP Default Rate Structure" scenario, 100% of customers would be enrolled in a critical peak pricing rate initially, and some 20% would eventually switch to a non-CPP rate structure, leaving 80% participation in year two and beyond. In the "CPP Elective" scenario, 0% of customers would sign up initially, ramping up to 20% in two years and beyond. (These rates are based on the experience from the California Statewide Pricing Pilot and other pilots.)

3) Conclusions Regarding Customer Benefits from Load Reductions

Figure 8 shows the benefits to Delaware customers (including municipal and cooperative utilities contained within the PHI zones) if Delmarva's proposed DSM programs are implemented in Delmarva-Delaware according to its proposed deployment schedule.

The following conclusions can be drawn from this analysis:

- For the Default CPP Case, the quantified benefits of load reductions would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM ($65-81 million for all of Delaware), but they are be much greater in the Inadequate Supply Response scenario ($84-107 million for all of Delaware).

- For the Voluntary CPP Case, the quantified benefits of load reductions would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM ($28-36 million for all of Delaware), but they are be much greater in the Inadequate Supply Response scenario ($36-47 million for all of Delaware).

- The short-term savings to all customers, including customers outside of PHI's zones, would be much larger than the benefits to just Delaware customers due to the fact that PHI's load reductions would have a market-wide impact on energy and capacity prices.

Figure 8. Benefits to Delaware Customers from AMI-Enabled Dynamic Pricing and Direct Load Control Programs in Delmarva Delaware for both Voluntary and Default Cases.

Benefits to Delaware Customers from AMI-Enabled CPP and DLC in Delmarva DE
Net Present Value of Benefits through 2024 (million 2007 $'s)

Rate Structure Scenario	CPP is a Voluntary Rate			CPP is the Default Rate		
Supplier Responsiveness Scenario*	Fast	Slower	Inadequate	Fast	Slower	Inadequate
RESOURCE COST SAVINGS						
Avoided Capacity Costs	$25	$25	$25	$57	$57	$57
Avoided Energy Costs	$3 - $9	$3 - $9	$3 - $9	$7 - $20	$7 - $20	$7 - $20
Avoided Ancillary Services Costs	$0.7 - $2	$0.7 - $2	$0.7 - $2	$0.9 - $2.5	$0.9 - $2.5	$0.9 - $2.5
SHORT-TERM MARKET PRICE IMPACTS						
Energy Price Benefit	$0.2 - $0.5	$0.9 - $2	$2 - $5	$0.4 - $1.1	$2 - $6	$5 - $13
Potential Additional Real-Time Benefit	$0.1 - $0.2	$0.2 - $0.4	$0.3 - $0.5	$0.3 - $0.7	$0.6 - $1.2	$0.9 - $1.5
Capacity Price Benefit	$0	$0	$6	$0	$0	$15
TOTAL QUANTIFIED BENEFITS * **	$28 - $36	$29 - $38	$36 - $47	$65 - $81	$67 - $85	$84 - $107
UNQUANTIFIED BENEFITS						
Enhanced Reliability			Large***			Very Large***
Enhanced Market Competitiveness						
Reduced Rate Volatility						
Environmental Benefits						
Reduced Transmission Losses						
Avoided Transmission and Distribution Costs						

* Fast response: short-term benefits last for 1 year; Slower response: short-term benefits last for 3 years;
Inadequate response: no generic entry and short-term benefits last until 2015.
** Excludes potential real-time benefits.
*** A PHI-wide implementation of AMIand energy efficiency would increase reserve margins in Eastern MAAC from 18.1% to 18.9% in 2010, and from 11.5% to 12.9% in 2013 if CPP is the Default Rate Structure and from 18.1% to 18.6% in 2010, and from 11.5% to 12.3% in 2013 if CPP is a Voluntary Rate Structure

- The savings to Delaware customers would be as much as two times larger if all utilities in PJM-East followed PHI's lead in deploying DSM programs and achieved similar load reductions, with the aggregate load reductions creating a much greater impact on energy and capacity prices.

- The savings to Delaware customers would be less than half as large if critical peak pricing were not the default rate structure, requiring customers to take initiative in order to sign up for the program. This finding is based on the assumption that a voluntary program would achieve only 20% participation by residential and small commercial and industrial customers, whereas making CPP the default rate structure with an option to switch to a fixed rate would achieve 80% participation. (This assumption is consistent with participation rates in

California's Statewide Pricing Pilot.) However, even at a pessimistic 20% participation rate, the total benefits of AMI/DSM exceed the total costs.

- Although critical peak pricing programs typically designate peak periods on a day-ahead basis, making the programs callable on a real-time basis would enable customers to mitigate the impacts of real-time surprises in load or supply outages. This could add an additional $300,000 to $1.5 million in value.

- In the Inadequate Supply Response scenario, implementation of DSM programs like PHI's throughout PJM-East would increase reserve margins in Southwest MACC from 15.2% to 18.3% in 2010, and from 5.8% to 14.4% in 2013; in Eastern MAAC from 18.1% to 21% in 2010 and from 11.5 to 19.9% in 2013. Hence, DSM initiatives would provide substantial value as an insurance against intolerably low reserve margins.

These savings estimates do not include potential additional customer benefits from reducing transmission losses, improving reliability, reducing rate volatility, enhancing market competitiveness, improving environmental quality, reducing energy prices by lowering the costs of environmental compliance, or potentially obviating or delaying the need for investments in transmission and distribution. These categories of benefits have not been quantified because the economic methodologies involved are not as well developed or standardized. Therefore, the total customer benefits of AMI could be substantially larger than the limited set of benefits reported in this Business Case.

Additional Benefits

Customer Benefits

Delmarva utilizes a market research model developed by Market Strategies Inc ("MSI") to assist the company in identifying the key drivers of customer satisfaction. The energy delivery benefits associated with AMI related to billing, customer service, energy information and reliability contribute positively to Delmarva's customer satisfaction performance once the full Blueprint plan is implemented. Additional customer benefits include:

- Improved website capabilities which will provide interval usage data to enable customers to understand when and how they are consuming energy at their homes and businesses.

- Individual customer load profile data can be useful in enabling the utility to target specific conservation programs or messaging to those customers who would achieve the maximum benefit. Delmarva's "My Account" software has the capability to provide "Energy Grams" to customers which would offer customized energy conservation information based on how they are currently using energy.

- AMI would enable Delmarva to provide for a "point of purchase" notification or understanding by consumers. Delmarva's "My Account" software has the capability of providing AMI metered customers with "My bill to date" which enables customers to see how much they have spent so far in any given month. The "My bill to date" feature also enables the utility to perform outbound notifications to customers letting them know when energy consumption or spending has reached customer prescribed levels. These notifications will raise awareness of energy use and contribute to changing consumer behavior towards conservation and environmental stewardship.

- AMI allows Delmarva to potentially offer "On-Request" meter reading services whereby a customer could request a specific meter reading which would show consumption information for a period of time (1 hour for example). This type of reading would be able to let customers see a "before and after" view of energy use which enables them to see the benefits of conservation.

- AMI will enable Delmarva to provide on-line assistance with rate evaluations. Customers would benefit from having an Interactive Rate Comparison program available on line to examine the cost savings potential of various rate options in a manner which is customized based on their actual historic load profile. Users would select among options and calculate the energy costs for each option automatically. Users could then print out a summary of the analysis to be used for making rate decisions.

- AMI provides improved customer service due to the ability to remotely verify or determine that a particular meter is currently in service or out of service. This helps to alert the customer that the problem may be on the customer side of the meter.

- With AMI, it would be possible to offer customers an option of changing their monthly billing due date. This could conceivably provide some cash flow and payment flexibility benefit for customers.

- AMI information will benefit our Customer Contact Centers by enabling Customer Service Representatives ("CSR's") to quickly identify the time of high customer usage. This would enable the CSR to offer enhanced levels of customer educations by explaining exactly when periods of high usage are occurring at the customer's home or business.

- AMI allows the Company to be less intrusive to customers by not having meter reading personnel in or near the customer's home or business.

Theft of Service

Delmarva expects to improve the detection of lost revenue due to energy theft and other metering issues and to ultimately reduce it by using the capabilities of the AMI system. The AMI system is expected to enhance Delmarva's ability to identify and recover lost revenue in three ways. First, by visiting all of Delmarva's meter locations during the initial AMI meter deployment, we anticipate that some percentage of the meters currently affected by tampering, diversion or other problem will be found and remedied. Second, once the AMI system is installed, Delmarva anticipates that additional data will be available to indicate the status of the meter as well as provide electronic notification of possible tampering. This functionality will permit more timely identification, investigation and remediation of possible theft events. Finally, by using the interval data from the AMI system coupled with the analytical capabilities provided by the MDMS, Delmarva expects to develop the capability to analyze usage and other patterns to discern possible theft cases, particularly with commercial accounts. According to the Edison Electric Institute ("EEI"), electric utilities typically estimate approximately one to three percent of their annual revenue is lost due to energy theft. If the expected AMI capabilities enable Delmarva to improve its energy theft recovery by 0.5% of its annual kilowatt hour sales, we estimate that the recovered volume would be about 47 million kilowatt hours or about $6.5 million per year, assuming a combined residential distribution and standard offer service rate of 13.75 cents per kilowatt hour. Customers might experience a small reduction in rates due to reduced losses from the electrical system as the costs of the diverted electricity are paid for by the actual responsible parties. This benefit, however, would represent a shift in cost responsibility among customers, rather than a reduction in total revenue requirement recovered from all customers and was no included in this analysis.

Costs to Deploy

This section of the report provides the initial cost estimates for the deployment of the AMI system and the associated meter data management system ("MDMS") by Delmarva's electric and gas delivery businesses. The costs will change as the Company conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated cost values. Below is Figure 9 summarizing total capital expenditures needed for the initial deployment of the AMI system and annualized O&M costs expected in the first full year after deployment, followed by a more detailed description of each cost category.

Figure 9

Line	AMI System Components	Initial Deployment Costs Only $ in ('000s) Electric		Gas		Combined
1	Meters, including Installation Cost	$ 42,783	$	9,195	$	51,978
2	Communications Network, including Installation Cost	$ 21,616	$	-	$	21,616
3	AMI Network Management System and Meter Data Management Sys	$ 4,417	$	1,828	$	6,245
4	Contingency	$ 4,680	$	1,543	$	6,223
	Total Capital Investment	$ 73,496	$	12,566	$	86,062
	AMI System Incremental Cost to Operate	**Annual Estimated Costs After Deployment $ in ('000s) Electric**		**Gas**		**Combined**
5	MDMS Software Maintenance & License Fees	$ 62	$	26	$	88
6	MDMS Hardware Leasing	$ 168	$	70	$	238
7	AMI Network Management System O&M	$ 196	$	81	$	277
8	Communications Network Infrastructure O&M	$ 273	$	-	$	273
	Total Incremental Cost to Operate	$ 699	$	177	$	876

Note that the costs in the figure above exclude certain one time costs described in number 9 below.

1) Meters and Installation Labor

Costs include new AMI meters that contain certain equipment "under glass" such a remote connect/disconnect switch for certain meters, communications modules where applicable and the associated installation labor. Prices for AMI equipment are estimated using filings from other utilities as well as initial quotes from a few vendors and the calculated estimates consider differences in commercial and residential equipment requirements. A value of $85.00 is used for the AMI base cost for residential electric meters and a $194.00 value is used for commercial electric meters. Additionally 98% of residential electric meters will require a $25.00 remote connect/disconnect switch, which is not required for the commercial electric meter. All existing gas meters will be retrofitted with an AMI communications module, estimated at $60 per module. Labor cost for installations/ retrofits is estimated at $16.50 per electric meter and $20.00 per gas meter. This brings the estimated cost for meters with the associated installation labor to about $52 million for Delmarva's electric and gas customers in Delaware.

2) Communications Network Infrastructure and Installation Labor

The communications network infrastructure solution is assumed to leverage Delmarva's already existing network. There will be no separate communications network for gas meters; instead the gas meter's communication modules will utilize the communications network deployed for electric meters. The cost of this component of the AMI system is more variable than the other components (i.e., meters and the network management IT system), given the different ways AMI vendors configure and price their communications networks combined with the variability of terrain, meter density and meter locations in Delaware. For purposes of this cost estimate, $70.00 per electric meter, including installation costs, was used. The total estimated costs for communications network infrastructure and the associated installation is about $22 million for Delmarva's electric and gas customers in Delaware.

3) AMI Network Management System and Meter Data Management System

This cost category captures the estimated costs associated with software applications, systems integration and computer hardware necessary to support AMI. System costs include categories for

- MDMS – software license, servers, storage, operating system, database management system, clustering software, and system design, configuration and integration
- Customer Presentment – servers, storage, and system design, configuration and integration
- PHI Integration – CIS and other IT systems integration.

The total estimated costs for the AMI Network Management System and the Meter Data Management System are about $6 million for Delmarva's electric and gas customers in Delaware.

4) Contingency

We determined that a contingency should be applied to the start-up and installation activities as a way to help manage the current uncertainty around the AMI cost estimate. A contingency amount comprising 7% of the capital investment for Delmarva, representing an amount of about $6 million is included to cover unexpected increases in equipment costs, labor costs or materials prices.

5 and 6) MDMS Software Maintenance, License Fees and Hardware Leasing

The MDMS will require software maintenance and license fee contracts with the system's vendor for system support, upgrades and the like. The operating costs for the hardware for the MDMS system include the hardware leasing costs for the servers, the data warehouse system and data storage capacity.

7) AMI Network Management IT System O&M

The AMI Network Management IT System has costs similar in nature to the MDMS with regard to software and hardware. Three additional FTEs are estimated to be required after AMI deployment to operate and maintain the AMI system for PHI.

8) Communication Network Infrastructure O&M

These costs include the estimated ongoing maintenance of the communications equipment needed to transmit the data back and forth between the meters on the customers' premises and the Company's offices. This cost is dependent on the mix of communication technologies Delmarva ultimately obtains through its procurement process.

9) Labor Related Costs

The reduction in certain types of work would be phased in after the 2008 deployment, with labor related costs being incurred over a three year period (2010 through 2012). These costs would include reassignment and retraining of Delmarva employees. The estimated cost of this one time expense is $1.1 million for the electric service and $0.4 million for the gas service.

Accelerated Depreciation

As stated in PHI's February 6, 2007 Blueprint for the Future filing and in the 2007 NARUC [3] Resolution to Remove Barriers to the Broad Implementation of Advanced Metering Infrastructure, the deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. To encourage the implementation of this new technology the Commission should adopt ratemaking policies that remove a utility's disincentive toward demand-side resources that reduce throughput; provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and provide depreciation lives for AMI that take into account the speed and nature of change in metering technology.

The business case reflects depreciation lives for AMI that take into the account the speed and nature of the change in metering technology. The

[3] See NARUC Resolution Attached in Appendix 2

business case reflects a recovery period of fifteen years for the AMI investment and five years for the recovery of the remaining costs associated with the existing metering system. As of December 31, 2006, Delmarva's existing electric metering system had a remaining net book value of about $26 million and the existing gas metering system's communication modules had a remaining net book value of about $3 million. At this time, Delmarva expects to be able to retrofit the existing gas meters with an AMI ready communications module and not replace the existing meters. In certain cases, Delmarva has gas meters with existing communications modules installed in customers' premises. These modules would not be compatible with the communication system needed for the AMI system and therefore accelerated recovery treatment similar to the existing electric metering system is appropriate. Depreciation calculations in the business case may need to be updated due to pending federal legislation.

[redacted]

Appendix 1

Developments in other jurisdictions

Congress with the passage of the Energy Policy Act of 2005 recognized the importance of advanced metering for growth in the development of electric demand response programs across the United States. To advance the development of such programs, Congress directed the Federal Energy Regulatory Commission ("FERC") to assess demand response resources currently in existence in the electric power industry. FERC conducted a survey where they requested information from every state on the number and uses of advanced metering, existing demand response and time-based rate programs within their state. As a result of this survey, states were required to consider the adoption of a smart metering standard for each of their state regulated utilities.

Many states took the FERC survey results and determined methods for confronting the rising energy costs within their particular states with Advanced Metering Infrastructure and Demand Response Programs. The following identifies several utilities which have obtained approval from their individual state regulatory commissions and are beginning implementation of intelligent meter technology, demand response and time-based rate programs within their operating jurisdictions. California and Texas utility companies have led the way in implementation of AMI and Demand Response Programs.

CALIFORNIA

The California Public Utilities Commission ("CPUC") in 2004, directed each of the state's regulated utilities to explore the option and feasibility of upgrading their home and small-business electric meters to digital intelligent meters, similar to the types used to measure energy usage by larger commercial customers. The CPUC's goal was for its state regulated utilities to significantly ease California's constrained energy resources by providing some form of demand response during periods of peak demand. The need for a smart metering standard was essential in California due to the increased growth in population and per-person energy use in the state. California's state energy policies require utilities to commit large amounts of resources to fund and implement energy efficiency programs.

Pacific Gas & Electric ("PG&E")

Pacific Gas & Electric in 2006 obtained approval from the CPUC for the universal deployment of an AMI system which required the installation of

5.2 million electric meters and 4.1 million gas meters throughout its operating territory. PG&E immediately began an AMI pilot program in Bakersfield, California to test the accuracy and performance of SmartMeter™ after winning approval from the CPUC. Mass deployment of PG&E's SmartMeter™ Program is expected to begin in late 2007.

Southern California Edison (SCE)

Southern California Edison obtained approval from the CPUC to replace its existing 5.1 million electric meters with "next generation" electronic intelligent meter technology beginning in 2009. Edison SmartConnect™ is Southern California Edison's AMI Program which aims to improve overall customer service by allowing customers to proactively manage their energy use and also save money through participation in programs with time-differentiated rates and demand response options. The Edison SmartConnect™ program is the first overhaul of SCE's metering system since 1949.

San Diego Gas & Electric ("SDG&E")

San Diego Gas & Electric obtained approval from the CPUC in April 2007 to begin implementation of "smart meter" technology for its estimated 1.4 million electric meters and retrofitting approximately 900,000 gas meters throughout its service territory beginning in 2008. SDG&E's approval also includes an agreement with the CPUC's Division of Ratepayer Advocates ("DRA") and the Utility Consumers' Action Network ("UCAN") to become a leader in emerging energy technologies through the use of a smarter electric distribution grid.

TEXAS

With the passage of House Bill 2129, the Texas Public Utility Commission was required to study the benefit to be derived by electric utilities in Texas from advanced metering. Because of the retail choice environment of the Texas retail market, the challenge exists for implementing advanced metering in a way that will maximize the benefits for the utility company, retail providers and customers. The Texas Commission has also initiated a separate project to evaluate potential demand response programs for the Texas utilities market.

Centerpoint Energy

Centerpoint obtained approval from the Texas Public Utility Commission in 2006 for implementation of smart meter technology for its more than three million electric and natural gas customers in the Houston area. Implementation of smart electricity meters began in November 2006 in selected areas of Houston.

TXU Electric Delivery

TXU Electric Delivery plans to have its 3 million automated meters by 2011, complementing an advanced grid intelligent enough to monitor electric service real-time. By year's end, TXU Electric Delivery expects to have 370,000 automated meters system-wide, including 10,000 BPL-enabled meters. The BPL-enabled network will serve approximately 2 million residential and commercial customers in Texas.

OTHER JURISDICTIONS

Several utility companies in other jurisdictions have either filed applications or have obtained approval for implementing advanced metering and demand response programs. A sampling of these utilities companies are outlined below.

- *Detroit Edison* ("DTE") – The Michigan Commission approved DTE's plan to replace 3 million electric meters. DTE is investing $330 million for implementation of this over the next six years. DTE has also created a Home Energy Saver audit tool on their website (mydteenergy.com) to help customers manage their energy use and obtain conservation tips.

- *Pennsylvania Power & Light Company* ("PPL") – PPL completed the installation of 1.3 million electric meters in 2004. PPL has created sections on its website dedicated to energy conservation efforts, including an energy calculator, detailed information about smart meters, safety concerns and an energy library for customers to learn more about energy usage in their homes.

- *Baltimore Gas & Electric Company* – BGE filed for approval by the Maryland Public Service Commission in early 2007 of its plan to deploy an AMI system and Demand Side Management Programs.

- *Southern Company* – Southern Company obtained Commission approval to replace 4.5 million electric meters in their four-state operating territory.

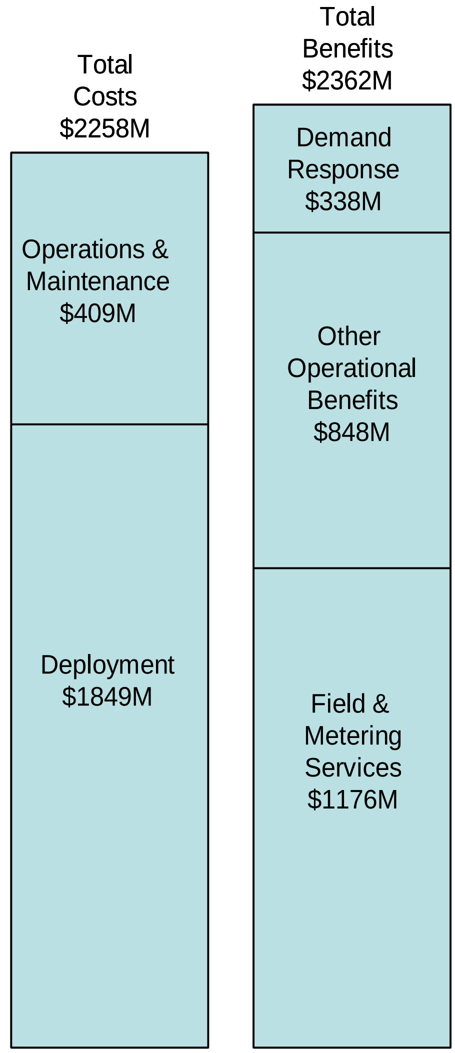
- *Portland General Electric ("PGE")* – PGE has filed an application with the Public Utility Commission of Oregon to install 843,000 smart meters for both residential and small non-residential customers throughout PGE's operating territory.

Business Case Summaries from Other Utilities

Summaries based on publicly available information from filings for PG&E Southern California Edison and San Diego Gas and Electric are included below. The summaries demonstrate the similarities in approach and results with PHI's AMI business case analysis.

Pacific Gas and Electric Company

The AMI business case filed by PG&E with the California Public Utilities Commission shows that AMI can largely be justified by the operational benefits and savings to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is $234 million on a present value revenue requirement (PVRR) basis. Adopting a benefit calculation* for Demand Response of $338 million which is more conservative than a Base Case* of $510 million still results in finding that the project is cost-effective.

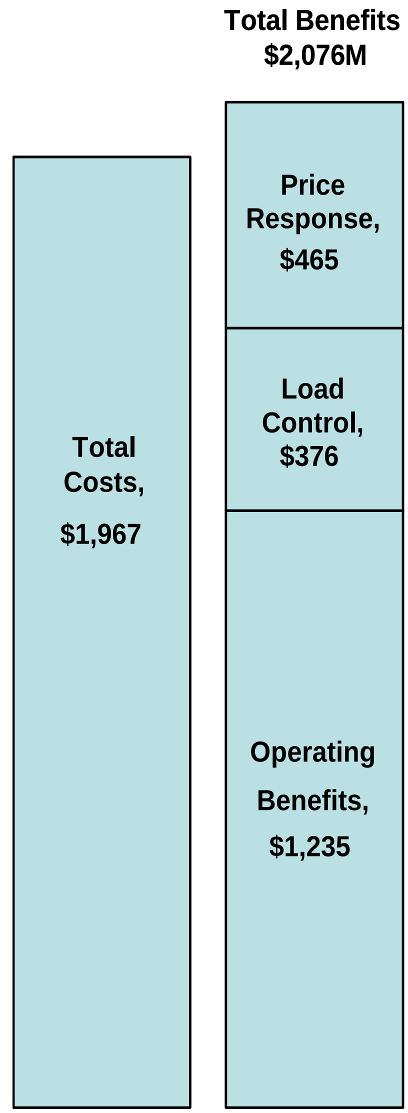


The field and metering services benefits include the reduction/elimination of the labor and non-labor costs required for regular meter reading and change of party/special reads and remote Turn-On/Shut-Off. Other operational benefits include improvement in Electric & Gas Transmission and Distribution restoration after significant outages, reduced customer calls and duration of calls related to billing and power outages, and reduced employee-related costs.

The major categories of deployment costs for AMI include meter and module equipment and installation costs, network equipment and install costs, and IT costs that include interval billing system, interface and integration costs. Operational and maintenance costs include AMI operation costs, meter operation costs, marketing and communications costs, and customer acquisition costs

Southern California Edison

The AMI business case filed by SCE with the California Public Utilities Commission shows that AMI is justified by the Operational, Load Control, and Price Response Benefits to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is $356 million on a present value revenue requirement (PVRR) basis. The new functionality of the Edison SmartConnect™ technology not only increases the ways in which customers can use demand response; it also results in SCE going from a negative $951 million Present Value Revenue Requirement (PVRR) in 2005,* to a positive $109 million PVRR in 2007 for full AMI deployment.



Through its AMI System Design and Use Case Process, SCE will integrate Edison SmartConnect™ into its operating systems to ensure that the expected benefits accrue in the areas of customer service, billing, outage management, and operations and maintenance.

Operational savings are forecast to cover approximately 63 percent of the related costs. Participation by residential and <200kW business customers in dynamic pricing and demand response programs is expected to provide sufficient additional benefits to justify the Edison SmartConnect™ project. The cost-benefit analysis is summarized in the Figure below.

* Source: EDISON SMARTCONNECT™ DEPLOYMENT

FUNDING AND COST RECOVERY

Volume 1 –Policy July 31, 2007 - Before the Public Utilities Commission of the State of California

Appendix 2 NARUC Resolution

Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure

WHEREAS, The Energy Policy Act of 2005 amended the State ratemaking provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA) to require every State regulatory commission to consider and determine whether to adopt a new standard with regard to advanced metering infrastructure (AMI); *and*

WHEREAS, Advanced metering, as defined by Federal Energy Regulatory Commission (FERC), refers to a metering system that records customer consumption hourly or more frequently and that provides daily or more frequent transmittal of measurements over a communication network to a central collection point; *and*

WHEREAS, The implementation of dynamic pricing, which is facilitated by AMI, can afford consumers the opportunity to better manage their energy consumption and electricity costs through the practice of demand response strategies; *and*

WHEREAS, Effective price-responsive demand requires not only deployment of AMI to a material portion of a utility's load, but also implementation of dynamic price structures that reveal to consumers the value of controlling their consumption at specific times; *and*

WHEREAS, AMI deployment offers numerous potential benefits to consumers, both participants and non-participants, including:

- greater customer control over consumption and electric bills;
- improved metering accuracy and customer service;
- potential for reduced prices during peak periods for all consumers;
- reduced price volatility;
- reduced outage duration; and,
- expedited service initiation and restoration; *and*

WHEREAS, The use of AMI may afford significant utility operational cost savings and other benefits, including:

- automation of meter reading;
- outage detection;
- remote connection/disconnection;
- reduced energy theft;
- improved outage restoration;
- improved load research;
- more optimal transformer sizing;
- reduced demand during times of system stress;
- decreased T&D system congestion; and,
- reduced reliance on inefficient peaking generators; *and*

WHEREAS, Sound AMI planning and deployment requires the identification and consideration of tangible and intangible costs and benefits to a utility system and its customers; *and*

WHEREAS, Cost-effective AMI may be a critical component of the intelligent grid of the future that will provide many benefits to utilities and consumers; *and*

WHEREAS, It is important that AMI allow the free and unimpeded flow and exchange of data and communications to empower the greatest range of technology and customer options to be deployed; *and*

WHEREAS, The deployment of cost-effective AMI technology may require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure; *and*

WHEREAS, Regulated utilities may be discouraged from pursuing demand response opportunities by the prospect of diminished sales and revenues; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its February 2007 Winter Meetings in Washington, D.C., recommends that commissions seeking to facilitate deployment of cost-effective AMI technologies consider the following regulatory options:

- pursue an AMI business case analysis, in conjunction with each regulated utility, in order to identify an optimal, cost-effective strategy for deployment of AMI that takes into account both tangible and intangible benefits;
- adopt ratemaking policies that provide utilities with appropriate incentives for reliance upon demand-side resources;
- provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and,
- provide depreciation lives for AMI that take into account the speed and nature of change in metering technology; *and be it further*

RESOLVED, That the Federal tax code with regard to depreciable lives for AMI investments should be amended to reflect the speed and nature of change in metering technology; *and be it further*

RESOLVED, That NARUC supports movement toward an appropriate level of open architecture and interoperability of AMI to enable cost-effective investments, avoid obsolescence, and increase innovations in technology products.

Sponsored by the Committee on Energy Resources and Environment
Adopted by NARUC Board of Directors February 21, 2007